TABLE 1 Classification of Coals by Rank[A]

Class/Group	Fixed Carbon Limits (Dry, Mineral-Matter-Free Basis), %		Volatile Matter Limits (Dry, Mineral-Matter-Free Basis), %		Gross Calorific Value Limits (Moist,[B] Mineral-Matter-Free Basis)				Agglomerating Character
					Btu/lb		MJ/kg[C]		
	Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	Equal or Greater Than	Less Than	
Anthracitic:									
Meta-anthracite	98	...	...	2	...	...	...	...	nonagglomerating
Anthracite	92	98	2	8	...	...	...	...	nonagglomerating
Semianthracite[D]	86	92	8	14	...	...	...	...	nonagglomerating
Bituminous:									
Low volatile bituminous coal	78	86	14	22	...	...	...	...	commonly agglomerating[F]
Medium volatile bituminous coal	69	78	22	31	...	...	...	...	commonly agglomerating[F]
High volatile *A* bituminous coal	...	69	31	...	14 000[E]	...	32.6	...	commonly agglomerating[F]
High volatile *B* bituminous coal	...	...	...	...	13 000[E]	14 000	30.2	32.6	commonly agglomerating[F]
High volatile *C* bituminous coal	...	...	...	...	11 500	13 000	26.7	30.2	commonly agglomerating[F]
					10 500	11 500	24.4	26.7	agglomerating
Subbituminous:									
Subbituminous *A* coal	...	...	...	...	10 500	11 500	24.4	26.7	nonagglomerating
Subbituminous *B* coal	...	...	...	...	9 500	10 500	22.1	24.4	nonagglomerating
Subbituminous *C* coal	...	...	...	...	8 300	9 500	19.3	22.1	nonagglomerating
Lignitic:									
Lignite *A*	...	...	...	...	6 300†	8 300	14.7	19.3	nonagglomerating
Lignite *B*	...	...	...	...	...	6 300	...	14.7	nonagglomerating

[A] This classification does not apply to certain coals, as discussed in Section 1.
[B] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.
[C] Megajoules per kilogram. To convert British thermal units per pound to megajoules per kilogram, multiply by 0.002326.
[D] If agglomerating, classify in low-volatile group of the bituminous class.
[E] Coals having 69 % or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of gross calorific value.
[F] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and that there are notable exceptions in the high volatile C bituminous group.
† Editorially corrected.

accordance with Test Methods D 1757 and express the result on a dry basis. Inherent moisture is reported as as-received moisture if the sample was collected according to 7.1.1, or as equilibrium moisture if 7.1.6 (Test Method D 1412) applies.

8.2 Adjust the ash value determined in accordance with Test Method D 3174 to be free of sulfate as follows:

$$A = A_d\left(1 - \frac{SO_3}{100}\right)\left(1 - \frac{M}{100}\right) \quad (1)$$

where:

A = adjusted ash value on the inherent moist basis,
A_d = ash yield, dry basis, determined in accordance with Test Method D 3174,
SO_3 = SO_3 in the ash determined in accordance with Test Method D 1757, and
M = inherent moisture.

Add to the value of fixed carbon that is determined in accordance with Practice D 3172 the value of the SO_3 determined in the ash to obtain the value FC to be used in Eq 2.

8.3 *Agglomerating Character*—The test carried out by the examination of the residue in the platinum crucible incident to the volatile matter determination shall be used.[3] Coals which, in the volatile matter determination, produce either an agglomerate button that will support a 500-g weight without pulverizing, or a button showing swelling or cell structure, shall be considered agglomerating from the standpoint of classification. In addition, a result of 1.0 or more on the Free Swelling Index test (Test Method D 720) may also be used to indicate the coal is agglomerating; a result of 0.5 or 0 indicates the coal is nonagglomerating.

9. Calculation to Mineral-Matter-Free Basis

9.1 *Calculation of Fixed Carbon and Calorific Value*—For classification of coal according to rank, calculate fixed carbon and gross calorific value to the mineral-matter-free (Mm-free) basis in accordance with the Parr formulas,[4] Eqs 2, 3, and 4.

9.2 Calculate to Mm-free basis as follows:

9.2.1 *Parr Formulas:*

$$\text{Dry, Mm-free FC} = 100\,(FC - 0.15S)/(100 - (M + 1.08A + 0.55S)) \quad (2)$$

$$\text{Dry, Mm-free VM} = 100 - \text{Dry, Mm-free FC} \quad (3)$$

$$\text{Moist, Mm-free Btu} = 100\,(Btu - 50S)/(100 - (1.08A + 0.55S)) \quad (4)$$

[3] Gilmore, R. E., Connell, G. P., and Nicholls, J. H. H., "Agglomerating and Agglutinating Tests for Classifying Weakly Caking Coals," *Transactions*, Am. Institute of Mining and Metallurgical Engineers, Coal Division, Vol 108, 1934, p. 255.

[4] Parr, S. W., "The Classification of Coal," *Bulletin No. 180*, Engineering Experiment Station, University of Illinois, 1928.

where:
Btu = gross calorific value, Btu/lb,
FC = fixed carbon (after adjustment for the adjusted ash), %,
VM = volatile matter, %,
M = moisture, %,
A = ash, %, and
S = sulfur, %.

Above quantities are all on the inherent moisture basis. This basis refers to coal containing its natural inherent moisture, but not including water adhering to the surface of the coal.

10. Keywords

10.1 anthracite; bituminous; coal; lignite; rank

APPENDIX

(Nonmandatory Information)

X1. CORRELATION OF VOLATILE MATTER WITH MEAN-MAXIMUM REFLECTANCE OF VITRINITE

X1.1 The reflectance of vitrinite in a sample of coal, as determined by Test Method D 2798, provides a useful guide to the rank of the coal. The correlation of the mean-maximum reflectance of all varieties of vitrinite with volatile matter, expressed on a dry and mineral-matter-free basis, is given in Fig. X1.1. Data are plotted for 807 coal samples that contained less than 8 % ash from many different coal fields in North America. All data were determined by a single laboratory, with several different analysts over a period of several years. The plot shows a range of reflectances for three important rank groups:

Reflectance Range in Oil, Mean-Max, %	Distribution Midpoints	Rank
<1.15	<1.1	hvb
1.02–1.55	1.10–1.45	mvb
1.35–2.0(?)	1.45–2.0(?)	lvb

X1.2 The midpoints given above are the midpoints of the distribution for the lower and upper boundary points on the reflectance scale for the indicated rank. Of the 807 coals, those that contain greater than 25 volume % inertinites tend to plot on the lower side of the distribution range than do the others that contain more vitrinites and liptinites.

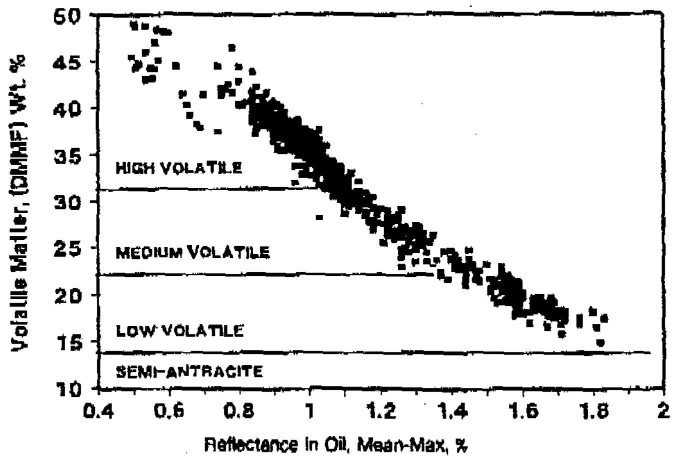

FIG. X1.1 Relation Between the Rank of U.S. Coals and Vitrinite Reflectance

The American Society for Testing and Materials takes no position respecting the validity of any patent rights asserted in connection with any item mentioned in this standard. Users of this standard are expressly advised that determination of the validity of any such patent rights, and the risk of infringement of such rights, are entirely their own responsibility.

This standard is subject to revision at any time by the responsible technical committee and must be reviewed every five years and if not revised, either reapproved or withdrawn. Your comments are invited either for revision of this standard or for additional standards and should be addressed to ASTM Headquarters. Your comments will receive careful consideration at a meeting of the responsible technical committee, which you may attend. If you feel that your comments have not received a fair hearing you should make your views known to the ASTM Committee on Standards, 1916 Race St., Philadelphia, PA 19103.

COLOWYO - CRAIG, CO

	AS RCD	AS DET.	DRY	INHERENT MOISTURE (EQ MOISTURE BASI.
MOIST	16.72	8.00	XXX	15.00
ASH	5.76	6.37	6.92	5.89
SUL	0.38	0.42	0.46	0.38
BTU	10461	11556	12561	10677

MOIST, Mm-free BTU $= 100(\text{BTU} - 50\underline{S}) / (100 - (1.08A + 0.55$

where BTU = gross calorific value, BTU/lb
A = ash %
$\underline{S}$ = sulfur %

Moist, Mm-free BTU $= 100(10677 - 19) / (100 - (6.36 + .21))$

$= 100(10658) / (100 - 6.57)$

$= 100(10658) / (93.43)$

$= 11407$

FSI Ø — nonagglomerating

subbituminous A

ANTELOPE - POWDER RIVER BASIN

	AS RCD	AS DET.	DRY	INHERENT MOISTURE (EQ MOISTURE BASIS)
MOIST.	26.50	16.25	XXX	25.21
ASH	5.25	5.98	7.14	5.34
SUL	0.22	0.25	0.30	0.22
BTU	8800	10027	11973	8955

Moist, Mm-free BTU = 100(BTU - 50 S)/(100-(1.08A+0.55S

where BTU = gross calorific value, BTU/lb
A = ash %
S = sulfur %

Moist, Mm-free BTU = 100(8955-11)/(100-(5.77+.12))
= 100 (8944)/(100-5.89)
= 100 (8944)/(94.11)
= 9504

FSI 0.34 - nonagglomerating

SUBBITUMINOUS B or C

ANTELOPE COAL COMPANY
TRACE ELEMENTS
Canyon Seam
Parts Per Million
Whole Coal, Dry Basis

	AVERAGE
Arsenic	0.88
Beryllium	0.38
Cadmium	0.18
Chromium	39.20
Fluorine	44.75
Lead	2.70
Manganese	7.31
Mercury	0.06
Nickel	2.98
Selenium	0.62
Vanadium	8.14

h:\groups\gec1mktg\quality\acc\trace.acc
October 30, 1998

TRACE METALS IN COAL (ppm)

	Bituminous Coal Presently Using	Proposed Subbituminous Mine #1	Mine #2
Arsenic	2.0	0.9	1.0
Beryllium	0.2	0.4	0.6
Cadmium	1.0	0.2	<0.2
Chromium	220.0	39.2	3.0
Copper	29.0	8.7	3.9
Lead	<3.0	2.7	4.0
Manganese	15.0	7.3	14.0
Mercury	0.22	0.06	0.04
Nickel	58.0	3.0	2.2
Zinc	28.0	4.7	6.0

Note that the results for the bituminous are from the mine where we presently get most of our coal from. Analysis results may change from time to time due to variations in the coal seam. Analysis may also vary from mine to mine.

Chlorine	7.0	0.01	0.0

ANTELOPE
TYPICAL COAL QUALITY
NORTH FIELD ANDERSON & CANYON SEAMS

PROXIMATE

% Moisture	26.50
% Ash	5.25
% Volatile	31.75
% Fixed Carbon	36.75
BTU/lb	8800
Sulfur	0.22

ULTIMATE

% Moisture	26.50
% Carbon	51.45
% Hydrogen	3.50
% Nitrogen	0.77
% Chlorine	0.01
% Sulfur	0.22
% Ash	5.25
% Oxygen	12.62

MINERAL ANALYSIS OF ASH

% Silica	32.00
% Alumina	15.90
% Titania	1.25
% Ferric Oxide	5.95
% Lime	23.15
% Magnesia	5.80
% Potassium Oxide	0.31
% Sodium Oxide	1.41
% Sulfur Trioxide	10.45
% Phosphorous Pentoxide	1.80
% Strontium Oxide	0.48
% Barium Oxide	0.75
% Undetermined	0.75
Base/Acid Ratio	0.77

ASH FUSION TEMPERATURES

Reducing (F)	
Initial	2130
Softening (H = W)	2150
Hemispherical (H = 1/2W)	2180
Fluid	2185
Oxidizing (F)	
Initial	2200
Softening (H = W)	2215
Hemispherical (H = 1/2W)	2230
Fluid	2260
T250 Temperature	2256
HGI (at as-received moisture)	60

COLOWYO
AFFILIATE OF Kennecott Energy
COAL COMPANY L.P.

TYPICAL PRODUCT SPECIFICATIONS

Based on 1995 Shipments
Colowyo Mine - Craig, Moffat County, Colorado
Rail - D&RGW
2 standard deviations from mean

PROXIMATE ANALYSIS

As Received Basis

	Average	Range	Min	Max
Moisture %	16.72	15.42 - 18.02	15.39	18.80
Ash %	5.76	4.41 - 7.11	4.44	8.61
Volatile Matter %	32.77	30.43 - 35.11	31.90	36.10
Fixed Carbon %	44.80	42.68 - 46.92	41.55	45.72
Sulfur %	0.38	0.28 - 0.48	0.26	0.54
Btu/Lb	10,461	10,183 - 10,739	10,054	10,792

Dry Basis

	Average	Range	Min	Max
Ash %	6.92	5.30 - 8.54	5.40	10.31
Volatile Matter %	39.28	36.62 - 41.94	38.27	43.16
Fixed Carbon %	53.68	51.00 - 56.36	49.65	54.72
Sulfur %	0.46	0.34 - 0.58	0.31	0.61
Btu/Lb	12,562	12,218 - 13,189	12,039	12,825

ULTIMATE ANALYSIS

As Received Basis

	Average	Range	Min	Max
Moisture %	16.72	15.42 - 18.02	15.39	18.80
Ash %	5.76	4.41 - 7.11	4.44	8.61
Sulfur %	0.38	0.28 - 0.48	0.26	0.54
Nitrogen %	1.36	1.26 - 1.46	1.27	1.41
Carbon %	60.72	59.20 - 62.24	59.25	62.05
Hydrogen %	3.95	3.77 - 4.13	3.81	4.04
Oxygen %	11.14	9.23 - 12.24	10.41	12.13
Chlorine %	0.00	0.00 - 0.00	0.00	0.01

Dry Basis

	Average	Range	Min	Max
Moisture %	--	--	--	--
Ash %	6.92	5.30 - 8.54	5.40	10.31
Sulfur %	0.46	0.34 - 0.58	0.31	0.61
Nitrogen %	1.63	1.53 - 1.73	1.54	1.69
Carbon %	72.78	71.44 - 74.12	71.96	74.31
Hydrogen %	4.74	4.54 - 4.94	4.57	4.89
Oxygen %	13.36	11.96 - 14.76	12.47	14.67
Chlorine %	0.00	0.00 - 0.00	0.00	0.01

HARDGROVE GRINDABILITY- (At as-received moisture)

Average	49
Range	45 - 52

SULFUR FORMS

	Average	Range	Min	Max
Pyritic %	0.03	0.01 - 0.05	0.03	0.05
Sulfatic %	0.01	0.00 - 0.02	<0.01	0.01
Organic %	0.34	0.28 - 0.40	0.36	0.47
Total %	0.38	0.29 - 0.47	0.40	0.53

EQUILIBRIUM MOISTURE

Average 15.00 %
Range 14.06 - 17.56%

ASH FUSION TEMPERATURES: °F

Reducing

	Average	Range	Min	Max
Initial	2239	2186 - 2292	2074	2300
Softening (H=W)	2294	2234 - 2354	2185	2352
Hemispherical	2369	2252 - 2486	2253	2568
Fluid	2593	2395 - >2700	2283	>2700

Oxidizing

	Average	Range	Min	Max
Initial	2307	2278 - 2336	2275	2337
Softening (H=W)	2317	2284 - 2340	2282	2347
Hemispherical	2344	2320 - 2368	2303	2392
Fluid	2441	2347 - 2535	2360	2501

ELEMENTAL ANALYSIS OF ASH

	Average	Range	Min	Max
Silicon Dioxide %	49.68	44.74 - 54.62	43.80	56.15
Aluminum Oxide %	20.63	18.43 - 22.83	17.18	23.01
Titanium Dioxide %	0.84	0.60 - 1.08	0.57	1.13
Ferric Oxide %	4.17	2.25 - 6.09	1.77	6.37
Calcium Oxide %	7.51	5.05 - 9.97	4.87	10.38
Magnesium Oxide %	1.08	0.74 - 1.72	0.31	1.52
Potassium Oxide %	0.88	0.58 - 1.18	0.54	1.39
Sodium Oxide %	1.95	0.81 - 3.09	0.89	2.95
Sulfur Trioxide %	10.28	8.32 - 12.24	8.33	12.65
Phosphorus Pentoxide %	1.43	0.73 - 2.13	0.56	2.47
Barium Oxide %	0.51	0.31 - 0.71	0.60	0.75

TRACE ELEMENTS IN WHOLE COAL BY MASS SPECTROSCOPY:

Element	Conc. Wt. PPM	Element	Conc. Wt. PPM
Antimony	<1	Manganese	14
Arsenic	1.0	Mercury *	.04
Barium	310	Molybdenum	<2
Beryllium	0.57	Neodymium	2
Boron	18	Nickel	2.2
Bromine	4	Niobium	4
Cadmium	<0.2	Praseodymium	2
Cerium	25	Rubidium	4
Cesium	4	Samarium	3
Chromium	3	Scandium	1
Cobalt	<1	Selenium	<1
Copper	3.9	Strontium	140
Europium	0.5	Tantalum	16
Fluorine **	46	Terbium	0.8
Gadolinium	2	Thorium	8
Gallium	6	Tin	<1
Germanium	0.3	Uranium	3
Hafnium	1	Vanadium	9
Iodine	0.2	Ytterbium	1
Lanthanum	2	Yttrium	14
Lead	4	Zinc	6
Lithium	3.9	Zirconium	13

* Determined by flameless atomic absorption spectroscopy.

** Determined by specific ion electrode.

INTERMOUNTAIN POWER SERVICE CORPORATION

December 10, 1996

Ursula K. Trueman, Director
Division of Air Quality
Department of Environmental Quality
P.O. Box 144820
Salt Lake City, Utah 84114-4820

Dear Director Trueman:

Notice of Intent (NOI) to Modify Approval Order BAQE-672-89

This letter is our Notice of Intent to modify Approval Order #BAQE-672-89 for the Intermountain Power Generating Station (IGS) coal fired steam-electric plant located in Millard County. Specifically, Intermountain Power Service Corporation (IPSC) intends to trial burn subbituminous coal to determine burn characteristics and performance parameters in preparation for future continuous use of this type of coal. If the trial burns are acceptable, IPSC may decide to use this type of coal on a permanent basis. Section 4 of the Approval Order requires a notice of intent to modify if coal other than bituminous is proposed for use.

As required by Utah Administrative Code R307-1-3.1.6, the following information is provided:

A. IGS is a fossil-fuel fired steam-electric generating station using coal as fuel for the production of steam.

IGS has bulk handling equipment for unloading, transfer, storage, preparation and delivery to the coal boilers. No changes in equipment are required or expected.

With the exception of fuel, no changes in the use of raw materials are required or expected.

Ursula Trueman
Page 2
December 10, 1996

The type of fuel will change from bituminous to subbituminous coal for several trial periods from January through September of 1997. Two types of subbituminous will be tested from different mines. Approximately 100,000 tons of subbituminous coal from Mine 1 and 300,000 tons from Mine 2 will be burned during this trial period. These subbituminous coals will be blended with bituminous coal at various ratios. Comparisons between these fuels are described below:

Parameter*	Bituminous (Present)	FUEL TYPE Subbituminous (Proposed) Mine 1	Mine 2
Moisture %	8.23	26.50	16.72
Ash %	9.42	5.26	5.76
Sulfur %	0.49	0.22	0.38
BTU/lb	11743	8800	10461

*Proximate Analysis Calculated Composites, As Received Basis

B. The expected composition and physical characteristics of emissions resulting from the use of subbituminous coal as fuel are expected to be unchanged from present emission composition and characteristics with regard to emission rates, temperature, air contaminant types and concentration of air contaminants. Subbituminous coal has lower thermal energy per pound than bituminous coal, requiring more tonnage of subbituminous coal to be combusted to meet comparable heat input. The mass flow of chimney effluent will increase proportionately with increased fuel usage and combustion air to meet comparable heat input.

C. Present pollution control equipment for combustion includes dual register low NOx burners, baghouse type fabric filters for particulate removal and flue gas desulfurization scrubbers. Dust collection filters are the control equipment for handling and transfer of solid fuel. No changes in the operation of pollution control equipment are required or expected.

D. The present emission point for IGS boilers is a lined chimney that discharges at 712 feet above ground level (5386 feet above sea level). The chimney location is 39° 39' 39" longitude, 112° 34' 46" latitude.

E. Emissions from boiler combustion are continuously sampled and monitored at the chimney for nitrogen oxides, sulfur oxides, carbon dioxide and volumetric flow. Opacity is measured at the fabric filter outlet. Other parameters recorded include heat input and production level (megawatt load). Monitoring will remain unchanged.

F. Operation at IGS is 24 hours per day. This will not change.

Overall, there does not appear to be any potential for net increases in air contaminants from the proposed change. Operational parameters, including pollution control and production levels, will remain the same. The intent of the NOI is to allow IPSC to burn subbituminous coal as well as bituminous coal on a permanent basis.

If you have any questions or require further information, please have your staff contact Mr. Stan Smith at (801) 864-6430.

Sincerely,

S. Gale Chapman

S. Gale Chapman
President & Chief Operations Officer

BL RJC:lbm

cc: Lynn Banks
George Cross
Chuck DeVore
Blaine Ipson
Aaron Nissen
Stan Smith

State of Utah

DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY

Michael O. Leavitt
Governor
Dianne R. Nielson, Ph.D.
Executive Director
Ursula K. Trueman
Director

150 North 1950 West
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(801) 536-4000 Voice
(801) 536-4099 Fax
(801) 536-4414 T.D.D.

DAQE-028-97

January 8, 1997

S. Gale Chapman
Intermountain Power Service Corporation
850 W Brush Wellman Road
Delta, Utah 84624-9546

Dear Mr. Chapman:

Re: Approval Order Modification for Coal Requirements
Millard County, CDS, A1, ATT, NSPS, Title V Major

The attached document is an Approval Order for the above referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Mr. Nando Meli. He may be reached at (801) 536-4052.

Sincerely,

Ursula K. Trueman

Ursula K. Trueman, Executive Secretary
Utah Air Quality Board

UKT:NM:aj

cc: Central Utah District Health Department
Mike Owens, EPA Region VIII

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

APPROVAL ORDER MODIFICATION FOR COAL REQUIREMENTS

Prepared By: Nando Meli, Engineer
801-536-4052

APPROVAL NUMBER

DAQE-028-97

Date: January 8, 1997

Source

Intermountain Power Service Corporation
S. Gale Chapman
801-864-6484

Ursula K. Trueman
Executive Secretary
Utah Air Quality Board

Abstract

Intermountain Power Service Corporation (IPSC) is requesting that they be allowed to burn subbituminous coal to determine the burn characteristics and performance parameters in preparation for future continuous use of this type of coal. The Approval Order (BAQE-672-89) dated October 24, 1989, requires that only bituminous coal can be used for the boilers. There will be no change in the allowed emission rates from the burning of the subbituminous coal. Therefore a 30-day public comment period was not held. The CFR Part 60, Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978) applies to the IPSC plant.

The above-referenced project has been evaluated and found to be consistent with the requirements of the Utah Administrative Code Rule 307 (UAC R307), and the Utah Air Conservation Act. A public comment period was not required for this project. This air quality AO authorizes the project with the following conditions and failure to comply with any of the conditions may constitute a violation of this order:

General Conditions:

1. This AO applies to the following company:

   Facility Location

   Intermountain Power Service Corporation
   850 West Brush Wellman Road
   Delta, Utah 84624

   Phone Number (801) 864-4414
   Fax Number (801) 864-4970

   The equipment listed below in this AO shall be operated at the following location:

   PLANT LOCATION:

   Universal Transverse Mercator (UTM) Coordinate System:
   4,391.1 kilometers Northing, 364.5 kilometers Easting, Zone 12

2. Definitions of terms, abbreviations, and references used in this AO conform to those used in the Utah Administrative Code Rule 307 (UAC R307), and Series 40 of the Code of Federal Regulations (40 CFR). These definitions take precedence unless specifically defined otherwise herein.

3. Intermountain Power Service Corporation shall operate the coal fired steam-electric plant according to the terms and conditions of this AO as requested in the Notice of

Intent dated December 10, 1996 and additional information submitted to the Executive Secretary dated December 12, 1996, and December 23, 1996.

4. A copy of this AO shall be posted on site. The AO shall be available to the employees who operate the air emission producing equipment. These employees shall receive proper instruction as to their responsibilities in operating the equipment according to all of the relevant conditions listed below.

5. This AO shall replace the AO, BAQE-672-89, dated October 24, 1989.

6. The main boilers shall be constructed and operated according to the specifications in the Contract Document Number 2010N, as submitted to the Executive Secretary on April 14, 1983.

7. The sulfur dioxide scrubbers for the main boilers shall be constructed and operated according to the specifications in the Contract Document Number 9255.62.0202, as submitted on April 14, 1983.

8. The fabric filters for the main boilers shall be constructed and operated according to the specifications in the Contract Document Number 9255.62.0203, as submitted on April 14, 1983.

9. No main boiler unit shall exceed 8.352×10^9 BTU/HR heat input rate, as determined by ASTM Method D3176, D2015-77, or D3286-82 and the coal feed rate measured by the plant instrumentation. Records of heat input will be kept for two years and made available to the Executive Secretary upon request. Calibration of the plant coal feed rate meters shall be approved by the Executive Secretary. The owner/operator may spray the coal with used oil as proposed in the notice of intent dated August 15, 1989.

10. The auxiliary boilers shall be installed according to the specifications in the letter dated March 27, 1984.

<u>Limitations and Tests Procedures</u>

11. No main boiler unit shall discharge to the atmosphere:

    A. Particulate matter as PM_{10} at a rate exceeding:

        (1) 0.020 lb/10^6 BTU heat input

    B. Sulfur dioxide at a rate exceeding:

        (1) 0.150 lb/10^6 BTU heat input

        (2) 10.0 percent of the potential combustion concentration

    C. Nitrogen oxides at a rate exceeding:

(1) 0.550 lb/10^6 BTU heat input

D. Visible emissions in excess of 20% opacity

12. The emission limitations in Paragraph 11 above shall be determined by the following procedures:

A. Particulate matter as PM_{10}: 40 CFR 60.48a, (a & b)

B. Sulfur dioxide: 40 CFR 60.48a, (a & c), (30-day average)

C. Nitrogen oxides: 40 CFR 60.48a, (a & c), (30-day average)

D. Opacity: 40 CFR 60, Appendix A, Method 9, and/or by six-minute averages of the output of the continuous emission monitor required by 40 CFR 60.47a and Section 4.6, UACR

E. Performance testing shall be completed by the time frame required by 40 CFR 60.8a. For the purpose of 40 CFR 60.8a, maximum production rate shall be a boiler heat input of 7.517x10^9 BTU/HR and initial start-up shall be the first day electricity is produced by the generator.

13. Emissions of particulate matter from the following dust collectors shall not exceed a concentration of 0.024 gr/dscf and the following rates:

A.	(1)	Rail car unloading (4 units)	15.3 LBS/HR each unit
	(2)	Transfer building one	7.1 LBS/HR
	(3)	Unit one 13A	6.9 LBS/HR
	(4)	Transfer building two	5.5 LBS/HR
	(5)	Transfer building four	3.7 LBS/HR
	(6)	Crusher building one	3.8 LBS/HR
	(7)	Unit one 13B	3.5 LBS/HR
	(8)	Unit two 14A	4.1 LBS/HR
	(9)	Unit two 14B	3.5 LBS/HR
	(10)	Limestone preparation building	3.5 LBS/HR

B. Stack testing of the dust collectors listed in 13.A (1, 2, and 3 above) shall be completed within 60 days of start-up of each unit. Stack testing of collectors listed in 13.A (4 through 10) shall be as directed by the Executive Secretary. Ducting of gas flow from those dust collectors shall be designed to meet the requirements of 40 CFR 60, Appendix A, Method 1. 40 CFR 60, Methods 2-5 shall be used for testing.

14. Visible emissions from the following dust collectors shall not exceed 20% opacity as determined by 40 CFR 60, Appendix A, Method 9:

A. Coal truck unloading

B. Reserve reclaim
C. Limestone truck unloading hopper
D. Reclaim hopper
E. Crusher building
F. Each of the dust collectors listed in 13.A 1 through 10

15. Fugitive emissions from the following sources shall be minimized by using the control techniques herein, and visible emissions from these sources shall not exceed 20% opacity and shall be evaluated in accordance with Section 4.1.9, UACR:

A. Coal and limestone conveyor belts - enclosed on three sides

B. Coal dumpers - underground receiving

C. Coal stack out - telescopic spout and wet suppression

D. Coal and limestone reclaim - underground plow

E. Coal and limestone storage active pile - residual moisture

F. Coal and limestone reserve pile - compacting and crusting agent

G. Limestone stack out - telescopic spout

H. Fly ash silo unloading - mix with scrubber sludge

I. Coal and limestone haul road - paved

J. Solid waste area access road - $CACl_2$ or other dust suppressant treatment

K. Solid waste haul road - watering

L. Solid waste/soil stockpile - watering

M. Solid waste burial pile - compaction and reseeding

N. Limestone dumpers - Burnley baffles and underground receiving

NOTE: A fugitive dust control plan shall be submitted to the Executive Secretary for approval prior to start-up of the specific operations and shall include as a minimum: control techniques proposed, quantity of suppressant (where applicable) and frequency of application (where applicable).

16. No auxiliary boiler unit shall discharge to the atmosphere emissions in excess of any of the following rates or concentrations:

A. PM_{10} - .10 LBS/10^6 BTU, 20 LB/HR

B. SO_2 - .69 LBS/10^6 BTU, 100 LB/HR
C. NO_x - .35 LBS/10^6 BTU, 58 LB/HR

17. Compliance with the emission limitations of Paragraph 16 shall be determined with the following test methods:

A. PM_{10} - 40 CFR 60, Appendix A, Methods 201 a or b
B. SO_2 - 40 CFR 60, Appendix A, Methods 1-4 and 6 or 8
C. NO_x - 40 CFR 60, Appendix A, Methods 1-4 and 7

18. Stack testing for demonstration of compliance with the particulate standard of Paragraph 16 shall be performed within 60 days of initial start-up of the auxiliary boilers. Stack testing for SO_2 and NO_x shall be performed if directed by the Executive Secretary.

19. Visible emissions from the auxiliary boilers shall not exceed 20% opacity as determined by 40 CFR 60, Appendix A, Method 9.

20. Combined annual fuel oil consumption of the two auxiliary boilers shall not exceed 50,000 barrels (equivalent to 10% capacity factor).

Fuels

21. Sulfur content of the fuel combusted in the auxiliary boilers shall not exceed .58% by weight as determined by ASTM Method D-4294-89. Each delivery of fuel shall be tested. Records of test results shall be maintained and shall be made available to the Executive Secretary upon request for two years. A summary of each quarter's test results shall be submitted with the quarterly CEM report. The summary shall contain the average sulfur content expressed as percent weight for the quarter.

Federal Limitations and Requirements

22. In addition to the requirements of this AO, all provisions of 40 CFR 60, New Source Performance Standards (NSPS)[1] Subparts A and Da, 40 CFR 60.1 to 60.18 and 40 CFR 60.4 to 60.49a (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) apply to this installation. A copy of the latest 40 CFR 60 Subparts A (section 60.8) and Da, dated July 1, 1993, is attached to this document as Appendix A. However, to be in compliance, this facility must operate in accordance with the most current version of 40 CFR 60.

23. Reports required by 40 CFR 60.49a shall be submitted to the Executive Secretary within the time frame specified in (I) of that part.

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[1] NSPS = New Source Performance Standards.

Monitoring - Continuous Emissions Monitoring

24. A quality control program for the continuous monitoring system required by 40 CFR 60.47a and Section 4.6, UACR, must be developed and implemented. As a minimum, the quality control program must have written procedures for each of the following activities:

    A. Installation of CEMs
    B. Calibration of CEMs
    C. Zero and calibration checks and adjustments for CEMs
    D. Preventive maintenance for CEMs (including parts inventory)
    E. Data recording and reporting
    F. Program of corrective action for inoperable CEMs
    G. Annual evaluation of CEM system

    The quality control program must be described in detail, suitably documented and approved by the Executive Secretary prior to the date of performance testing.

Records & Miscellaneous

25. Malfunctions of process or air pollution control equipment shall be reported and handled in accordance with Section 4.7, UACR, and 40 CFR 60.46a.

26. Post construction monitoring of ambient air for at least one year after start-up is required. A monitoring and quality assurance plan for post construction monitoring must be submitted for approval by the Executive Secretary no later than six months before initial start-up of either boiler.

27. All installations and facilities authorized by this approval order shall be maintained and operated in proper condition.

28. The Executive Secretary shall be notified upon start-up/normal operations as an initial compliance inspection is required.

29. All installations and facilities authorized by this AO shall be adequately and properly maintained. Maintenance records shall be maintained while the plant is in operation. All pollution control vendor recommended equipment shall be installed, maintained, and operated. Instructions from the vendor or established maintenance practices that maximize pollution control shall be used. All necessary equipment control and operating devices, such as pressure gauges, amp meters, volt meters, flow rate indicators, temperature gauges, CEMS, etc., shall be installed and operated properly and easily accessible to compliance inspectors. A copy of all operating procedures or manufacturers' operating instructions for CEMs and any new additional pollution control equipment and pollution emitting equipment shall be kept on site. These instructions shall be available to all employees who operate the equipment and shall be made available to compliance inspectors upon their request.

30. The owner/operator shall comply with R307-1-3.5, UAC. This rule addresses emission inventory reporting requirements.

31. The owner/operator shall comply with R307-1-4.7, UAC. This rule addresses unavoidable breakdown reporting requirements. Any breakdown lasting longer than two hours shall be reported to the Executive Secretary within three hours of the breakdown if reasonable, but in no case longer than 18 hours after the beginning of the breakdown. During times other than normal office hours, breakdowns for any period longer than two hours shall be initially reported to the Environmental Health Emergency Response Coordinator. Within seven calendar days of the beginning of any breakdown lasting longer than two hours, a written report shall be submitted to the Executive Secretary. The owner/operator shall calculate/estimate the excess emissions (amount above AO limits) whenever a breakdown occurs. The total of excess emissions <u>per calendar year</u> shall be reported to the Executive Secretary <u>with the inventory submittal</u>, as directed by the Executive Secretary.

32. All records referenced in this AO or in applicable NSPS which are required to be kept by the owner/operator, shall be made available to the Executive Secretary or executive secretaries representative upon request and shall include a period of two years ending with the date of the request. All records shall be kept for a period of two years (used oil records are to be kept for a period of three years). Examples of records to be kept at this source shall include the following as applicable:

A.	Heat input	(Condition number 9)
B.	Auxiliary boiler fuel sulfur content	(Condition number 21)
C.	CEMS[2] records	(Condition number 24)
D.	Maintenance records	(Condition number 29)
E.	Emission inventory	(Condition number 30)
F.	Upset, breakdown episodes	(Condition number 31)

Any future modifications to the equipment approved by this order must also be approved in accordance with R307-1-3.1.1, UAC.

The Executive Secretary shall be notified in writing if the company is sold or changes its name. The notification shall be submitted within 30 days of such action.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including the UAC R307.

Annual emissions for IPSC coal fired steam-electric plant are currently calculated at the following values:

[2] CEMS = Continuous Emission Monitor System

	Pollutant	Tons/yr
A.	PM_{10}	77.66
B.	SO_2	3,639.
C.	NO_x	18,125.
D.	CO	630.
E.	VOC	0.43

These calculations are for the purposes of determining the applicability of Prevention of Significant Deterioration, nonattainment area, and Title V source requirements of the UAC R307. They are not to be used for purposes of determining compliance.

In accordance with the requirements of Title V of the 1990 Clean Air Act, the following pollutants may be subject to an operating permit fee. Emissions of the following pollutants from all sources, including pre-November 29, 1969 sources, may be subject to the operating permit fee. Both the fees rate and the class of pollutants are subject to change by State, the federal agencies, or both.

	Pollutant	Tons/yr
A.	PM_{10}	77.66
B.	SO_2	3,639.
C.	NO_x	18,125.
D.	VOC	0.43

Approved By:

Ursula K. Trueman

Ursula K. Trueman, Executive Secretary
Utah Air Quality Board

Appendix A

40 CFR 60 Subparts A (section 60.8 - 60.11) and Da, dated July 1, 1994.

Subpart A
§ 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard,
or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act. (c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. (e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974; 42 FR 57126, Nov. 1, 1977; 44 FR 33612, June 11, 1979; 54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989]

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:
(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.
(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by § 60.8, unless otherwise specified in the applicable standard.
(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).
(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.
Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e)(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in § 60.8 unless one of the following conditions apply. If no performance test under § 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under § 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in § 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test
conducted under § 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Reference Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determing compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under § 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in
the notification required in § 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by § 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and § 60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during

any performance test required under § 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under § 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under § 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under § 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under § 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in § 60.13(c) of this part, that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by § 60.8, the opacity observation results and observer certification required by § 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by § 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with § 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

[38 FR 28565, Oct. 15, 1973, as amended at 39 FR 39873, Nov. 12, 1974; 43 FR 8800, Mar. 3, 1978; 45 FR 23379, Apr. 4, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 51 FR 1790, Jan. 15, 1986; 52 FR 9781, Mar. 26, 1987]

Subpart Da- Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Source: 44 FR 33613, June 11, 1979, unless otherwise noted.

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:
(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and
(2) For which construction or modification is commenced after September 18, 1978.
(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG.)
(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.
(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.
Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).
Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.
Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.
Subbituminous coal means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388-77 (incorporated by reference-see §60.17).
Lignite means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-77 (incorporated by reference-see §60.17).

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Potential combustion concentration means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 75 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under § 60.48a(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

Combined cycle gas turbine means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

Interconnected means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment. Electric utility company means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

Principal company means the electric utility company or companies which own the affected facility.

Neighboring company means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

Net system capacity means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

System load means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

System emergency reserves means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Available system capacity means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

Spinning reserve means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power-distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

Available purchase power means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

Spare flue gas desulfurization system module means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

Emergency condition means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

Electric utility combined cycle gas turbine means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

Potential electrical output capacity is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

Anthracite means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-77 (incorporated by reference-see §60.17).

Solid-derived fuel means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.

24-hour period means the period of time between 12:01 a.m. and 12:00 midnight.

Resource recovery unit means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Boiler operating day means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours.

[44 FR 33613, June 11, 1979, as amended at 48 FR 3737, Jan. 27, 1983]

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.43a Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases which contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section), any gases which contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be conducted under § 60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC-I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery facility, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

Es=(340x+520 y)/100 and
%Ps=10

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

Es=(340x+520 y)/100 and
%Ps=(10x+30 y)/100

where:
Es is the prorated sulfur dioxide emission limit (ng/J heat input),
%Ps is the percentage of potential sulfur dioxide emission allowed.

x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)
y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

[44 FR 33613, June 11, 1979, as amended at 54 FR 6663, Feb. 14, 1989; 54 FR 21344, May 17, 1989]

§ 60.44a Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraph (b) of this section, any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

(1) NOx emission limits.

Fuel type	Emission limit for heat input: ng/J	Emission limit for heat input: (lb/million Btu)
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse.	({1})	({1})
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace{2}.	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit{2}.		

Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

{1}Exempt from NOx standards and NOx monitoring requirements.
{2} Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) NOx reduction requirement.

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25
Liquid fuels	30
Solid fuels	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.
(c) When two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$En=[86\ w+130x+210\ y+260\ z+340\ v]/100$$

where:
En is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);
w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;
x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;
y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;
z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

§ 60.45a Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(c) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NOx emission limitation and percent reduction under § 60.44a(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC I)	SO_2	6,000-10,000
Fluidized bed combustion (atmospheric)	SO_2	400-3,000
Fluidized bed combustion (pressurized)	SO_2	400-1,200

Coal liquification............................	NOx	750-10,000
Total allowable for all technologies.......		15,000

§ 60.46a Compliance provisions.

(a) Compliance with the particulate matter emission limitation under § 60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under § 60.42a(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under § 60.44a(a) constitutes compliance with the percent reduction requirements under § 60.44a(a)(2). (c) The particulate matter emission standards under § 60.42a and the nitrogen oxides emission standards under § 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed, (2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (h) under § 60.43a for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under § 60.43a and the nitrogen oxides emission limitations under § 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under § 60.43a and the nitrogen oxides emission limitation under § 60.44a is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO2 and NOx for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NOx only), or emergency conditions (SO2 only). Compliance with the percentage reduction requirement for SO2 is determined based on the average inlet and average outlet SO2 emission rates for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.47a of this subpart, compliance of the affected facility with the emission requirements under §§ 60.43a and 60.44a of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

§ 60.47a Emission monitoring.

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility which qualifies under the provisions of § 60.43a(d), sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An ``as fired'' fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 (appendix A) may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) The owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph § 60.13(h) are expressed in ng/J (lbs/million Btu) heat input and used to calculate the average emission rates under § 60.46a. The 1-hour averages are calculated using the data points required under § 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO2 concentration at the same location as the SO2 monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 shall be used to determine the NOx concentration at the same location as the NOx monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O2 or CO2 concentration at the same location as the O2 or CO2 monitor. Samples shall be taken for at least 309 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under § 60.13(c) and calibration checks under § 60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 6, 7, and 3B, as applicable, shall be used to determine O2, SO2, and NOx concentrations.

(2) SO2 or NOx (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N2, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

	Span value for

Fossil fuel	nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid	1,000
Combination	500 (x+y)+1,000z

where:
x is the fraction of total heat input derived from gaseous fossil fuel,
y is the fraction of total heat input derived from liquid fossil fuel, and
z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under § 60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990]

§ 60.48a Compliance determination procedures and methods.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section for SO2 and NOx. Acceptable alternative methods are given in paragraph (e) of this section.

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§ 2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The Fc factor (CO_2) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of § 60.46(d)(1). The CO_2 shall be determined in the same manner as the O_2 concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19 (appendix A). The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 (appendix A) calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990]

§ 60.49a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NOx only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of ``F'' factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system. (9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by § 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of § 60.46a(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates (ni) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (so) and inlet emission rates (si) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (Eo*) and the upper confidence limit for the mean inlet emission rate (Ei*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (Eo*) and the allowable emission rate (Estd) as applicable.

(d) If any standards under § 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under § 60.46a(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under § 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of § 60.48a and Method 19 (appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(h) For the purposes of the reports required under § 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under § 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(i) The owner or operator of an aff ected facility shall submit the written reports required under this section and subpart A to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.